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An Integrated Approach to Understanding the Performance of a Strong Water Drive Stratified Reservoir

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ABSTRACT

The performance of a thirteen-year old water drive reservoir in Mobil Producing Nigeria Edop field, located offshore Nigeria in about bolt water depth was recently evaluated. Excessive water production had caused the shut-in of three producers from this reservoir. The evaluation process started from the building of a geocellular model through material balance analysis and reservoir simulation study. This integrated approach utilized information obtained from well logs, Repeat Formation Test (RFT), fluid PVT analyses and routine production data. The result of the evaluation indicates that recovery factor of over 60% is possible in the Edop BQI reservoir. Aquifer influx, rather than coning. was found to be mainly responsible for the excessive water production and eventual shut-in of some wells. When two horizontal well completions were simulated as replacement for shut-in wells, they did not perform better than the conventional well's re-completions also simulated at the same location. Structurally higher re-completions and work-over of conventional wells were found to be more attractive. The integration of material balance results into a simulation model gave a better history match and indicated the need to modify geologic mapping in areas with less well control. This led to a potential for significant increase in reserves. Since completion of the study, Reservoir Saturation Tool (RST) logs have been run in several wells with results complimenting study conclusions. The study recommended work-over, re-completion of watered-out wells higher up structure and improvement in water handling as the best approach to maximising reserve recovery. It also recommended future efforts be focused on timely re-completion of watered out wells.

Keywords: Water drive, Saturation, work over, Aquifer influx, reservoir, primary energy, simulation and horizontal wells.

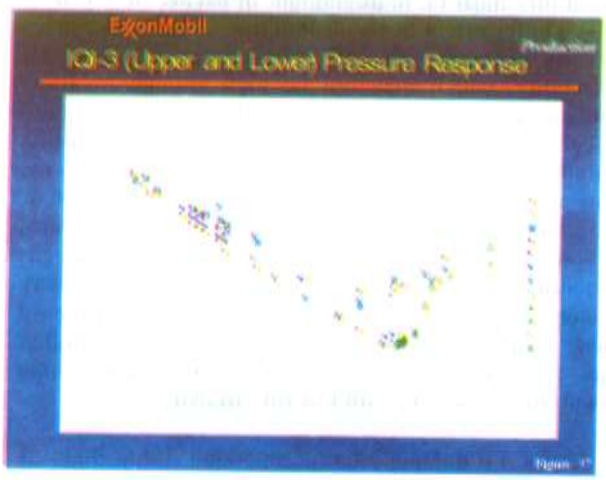
INTRODUCTION

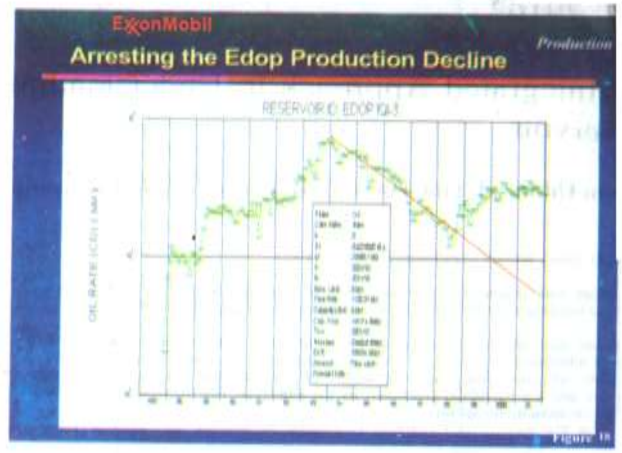
The production performance of a water drive reservoir is usually characterized by a slow but steady decline in reservoir pressure and oil producing rate with a corresponding continual increase in water production. Water drive is one of the primary energy drive mechanisms in hydrocarbon reservoirs. In the Niger Delta, combination drive is common although most reservoirs have associated aquifers of varying sizes. During oil production, reservoir pressure drops. The pressure drop is transmitted to the aquifer causing the water to expand and flow into the oil zone, known as water influx. The effectiveness of the water drive is determined by two main factors namely, aquifer size and the aquifer permeability. The size of the aquifer relative to a reservoir is roughly described by the dimensionless ratio $r_D = r_a/r_R$, which is the ratio of the aquifer radius to the reservoir radius[4], For strong water drive reservoirs, r, is usually greater than 40. Edop BQI aquifer volume to hydrocarbon ratio is estimated at 140:1. However, the permeability must be high enough, in excess of 1 Darcy, for the aquifer effect to be meaningful. Most water drive reservoirs, are rate sensitive due primarily to aquifer permeability, which may not be high enough to allow instantaneous pressure response. If reservoir pressure tails below saturation pressure, the release and expansion of solution gas adds to the reservoir energy to reduce the rate of pressure drop. Well intervention programs such as work-overs and horizontal re-drills are used to control reservoir energy loss from excessive water and gas production. Field examples of water drive recovery efficiency ranges from 20 percent to 90 percent of the oil in place, with average of about 53 percent[4]. The higher range recoveries are known to come from high permeability reservoirs with low oil viscosity.

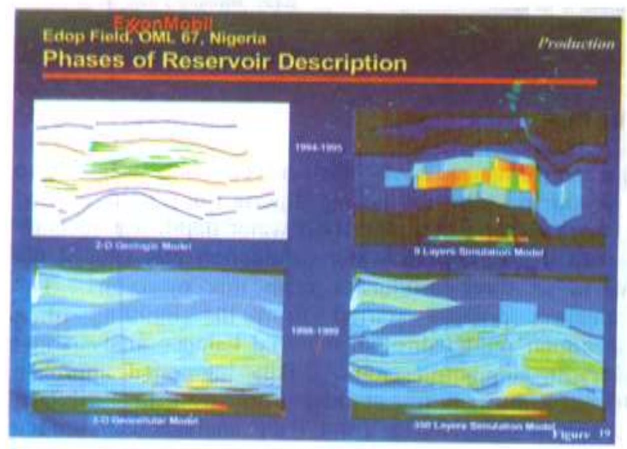
The xyz Producing Nigeria operated' Edop field is located in OML 67, approximately 40 km south of Eket, in the Niger Delta area (Figure 1). The field was discovered in 1981 with hydrocarbon bearing sands in the Base Qua lboe (BQI) and Intra Qua lboe (IQI) units of the lower Pliocene age. Four wells have drained the SQl reservoir since production commenced in 1987.


ExxonMobil
Production
Edop IQI Performance Plot


ExxonMobil
Production
Edop IQI Performance Plot


ExxonMobil
Production
IQI-3 (Upper and Lower) Pressure Response
Figure 17


ExxonMobil
Production
Arresting the Edop Production Decline
RESERVOIR ID: EDOP IQI-3
OIL RATE (CD) (MB/D)
Figure 18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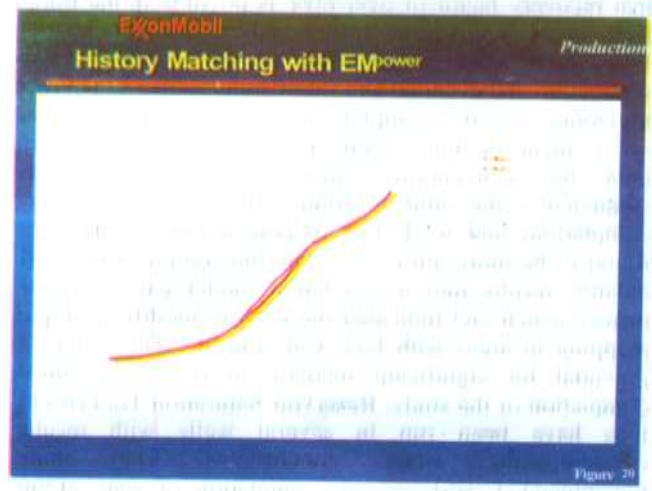
Edop Field, OML 67, Nigeria
Production
Phases of Reservoir Description
1994-1995
2-D Geologic Model
9 Layers Simulation Model
1998-1999
3-D Geocellular Model
Figure 19


ExxonMobil
Production
History Matching with EMpower
Figure 20

The reservoir has produced about 45 percent of the booked reserves with pressure decline of only 12%. A rapid movement in the oil-water contact was observed in the reservoir leading to water breakthrough and eventual shut- in of three wells. One of the shut-in wells was subsequently worked-over restoring its production rate of 3000 stb/d. In 1999. The oil-water contact was estimated to have moved at about two feet per one million stock tank barrel of oil produced. The reservoir has permeability, ranging from 0.1 milidarcies to 10,000 milidarcies with an average of about 2000 milidarcies. The BQI reservoir started production with solution GOR of 760 scf/stb, 38 API gravity and at initial reservoir pressure of 2860 psia.

Geologic model

Within the BQI stratigraphy, two units (‘A and ‘B’) are identified. Both are sand-rich, indicative of a high-energy environment of deposition and are represented as a lower delta plain to strand plain environment. Both sequences can be mapped seismically without difficulty. Beneath the Biafra B the stratigraphy is predominantly shale.

Structurally, the Edop Biafra reservoir is a faulted fourway dip closure that is overlain by the BQI unconformity[2]. The unconformity is angular in nature over the hydrocarbon bearing portions of’ the structure, becoming more conformable on the flanks (Figure 2), The reservoir is fault-bounded on the north by east-Northeast trending, down to the north fault with a throw of up to 100 feet. A small north trending, down to the east, non-sealing fault located in the eastern portion of the ‘mid, with a throw up to 40 feet has been identified. the axis of the small fault is an area where the SQl unconformity cuts through the Biafra ‘A’ unit and into the Biafra B’. This portion of the unconformity separates the reservoir into two connected pools (Figure 3 and 4)[2]

Reservoir Performance

The performance of the BQI sand is typical of a water drive oil reservoir. Figure 5 includes the reservoir production performance plot and it shows declining oil productivity with increasing water production. Three of the wells, OIA, 13A & 21D, were shut-in due to excessive water production. The water production from the wells in this reservoir did not respond to production rate sensitivity. This suggests strong water influx and negligible effect of water coning. Figures 6a, b, c & d show the performance of the four wells completed in this sand.

Well 01A established the original water contact at 6578 feet subsea in 1981. Its lower completion point was 38 feet above the water contact, Production peaked close to 6000 stb/d of oil and gradually declined 6 years later with the sustained increase in water production rate from 0 to 3000 b/d representing 60 percent water cut. The well was eventually shut-in due to high water production in 1997 and a work-over performed, plugging back the bottom 47 feet of the initial 89 feet completion length. This attempt to control water production did not last long as water encroached again and the well quit within one year.

Well 10A is completed structurally higher up structure and produces water free. However, an early gas breakthrough was observed and peaked above 2000 scf/stb in 1991. In 1994, a gradual decrease in the gas production was also observed and it did not respond to production rate increase from about 3500 stb/d to 4500 stb/d. The early gas breakthrough is suspected to have significantly depleted the expanding gas cap volume resulting in the reduced producing GOR shown in Figure 6b.

Well 13A had a brief production life due to the proximity of its completion to the water contact and its structural position. Well 21 D was completed structurally higher from the water contact than 13A by 52 ft, however, its completion have also been flooded by the advancing aquifer shown in Figure 7 .

Fluid Contacts Movements

Figure 7 illustrates results of surveillance analyses on the oil-water contact movement carried out in this reservoir. The oil-water contact was obtained from RFT and well logs of in-fill wells penetrating the sand as well as cased hole logging of existing well bores.

Based on Edop 01A the BQl reservoir had original gas along oil contact (GOC) at 6396 ftss and an original oil-water contact (OWC) at 6578 ftss. Each is clearly differentiated on wireline logs. The reservoir was streamed in February 1987. Later wells noted gas and water movements as shown in Figure 7. Due to strong water support, the OWC has advanced faster than the GOC. By 1989, when well 10A was drilled, evidence of aquifer movement was noticeable (flushed zone with a high residual oil saturation of about 30%) below 6556 feet subsea.

By 1990 when well 13A was drilled the water contact was observed at 6561 ftss, showing a 17 feet rise. At this time about 8.0 Mstb of oil had been recovered from wells O1A and 10A. By 1993 when well 21D was drilled, the water contact was encountered at 6508 ftss, showing 70 ft rise with a cumulative oil production of 20.0 Mstb from 3 wells. By December 1999, well 39E pilot hole established OWC at 6473 feet subsea, showing a 105 feet rise in OWC above original. At this time, cumulative oil production was approximately 38.0 Mstb. Well 13D, which had 70 feet completion between 6454 to 6524 ftss, was water-flooded and stopped producing after about 3 years. Well 21D with about 30 ft completion length between 6447 and 6472 ftss, suddenly broke through with water in June 1999 suggesting the OWC to have reached its lower perforations at 6472 ftss. Production from the reservoir has been limited due to the shut in of three of its four producers. Wells 21D is currently shut-in due to excessive water production. Currently, only well 10A is producing and is predicted to produce water free for some time. Currently the OWC is estimated at 6466 ftss from CNL log of well 0lA in December 1999 when cumulative oil production was about 48 Mstb. The new water contact indicates about 70 ft oil column is remaining using the original GOC. However marginal movement In the GOC was also recorded in 1999 CNL log suggesting 6414 as the new GOC The gradual reduction in gas production from well 10A, even with a significant Increase in oil production. Suggest that some volume of the expanding gas cap may have been produced. The GOC may have changed to the present level as a response to this gas cap depletion and stronger water influx. Figure 8 is a diagnostic plot used to evaluate the gas cap volumetric changes it shows that initial gas cap may have grown by a net 5 GSCF in 1990 due to the release of solution gas from the oil with pressure decline. This gas cap expansion may have resulted in gas coning noticed in well 10A The plot suggests a current net 2 GSCF gas addition to the initial gas cap volume and a new GOC of 6414 ftss observed in well OIA by 1999.

Simulation Modeling

EM^{power}, ExxonMobil's proprietary stare of the art reservoir simulator was used to simulate the Edop BQI reservoir. The geocellular model but using Landmark SGM (Figure 9) was imported into Flogrid and upscaled. Flogrid unstructured gridding option was used to generate 42 X 34 X 40 grid nodes. The three-compartment model is shown in Figure 10, mapped with full pressure communication across the faults. This model was initialized with 113 Gstb of oil, 58 GSCF of associated In the gas cap and 17 Gstb of water. A critical analysis of the model after many unsuccessful history match attempts indicated lack of adequate reservoir energy support arid lower STOHP Average water saturation was computed within the SGM modeled as 15% while average porosity was 29% Initial reservoir pressure was 2860 psia and was the same as the fluid saturation pressure. The fluid initial formation volume factor from PVT as .45 rb/stb while initial solution GOR was 780 scf/stb. Depending on the geologic facie, horizontal permeability ranges from about 01 md to 10 darcy An independent material balance analyses assessment was carried out to provide understanding of the reservoir energy support system and other parameters.

Material Balance Application

The material balance analyses was carried out, primarily, to evaluate STOOIP and aquifer volume. The MBAL software was used in carrying out the analyses. Aquifer influx was modeled using the modified Hurst van Everdingin-Odeh water influx model. Figure-1l shows results of analytical method and the energy plots. These plots give a better understanding of the usefulness of the water influx and the contribution of the different drive mechanisms. The matched model suggests aquifer volume of about 30 ORB, STOOIP of 130 Mstb to match production history and reservoir energy. The initial reservoir gas to oil volume ratio m, was matched at 0.17. The energy drive plot indicate a declining gas cap contribution while water influx energy contribution increased from about 40% to about 85% at the end of history in 2000. Table I shows the results from material balance compared with the geologic model results. These results were incorporated into the reservoir simulation model where the aquifer volume was consequently increased to 27 GSTB to match observed reservoir pressures.

History Match Model

Based on the results of the material balance analyses, some modifications were recommended for incorporation into the geologic model. The geologic changes included extending structural Contours in areas with no well control and poor seismic resolution, effectively lifting the reservoir tops by a few feet and increasing the STOOIP. Rock pore volume was also increased in one of the last layers to increase aquifer volume and provide u better history match. Th linl STOOIP used to obtain a good history match was 25 Msrtb and is included in Table 1Figure 6 includes the final history match plots obtained with the model The model was run on historical oil rate mode while reservoir pressure, water and gas productions were matched Special emphasis was placed on matching water breakthrough times as well as getting well 01A gas breakthrough and eventual decrease to solution gas to match.

Figure 12 is a cross-section plot showing the initial and end of history match water contacts. The plot shows the level of water Invasion and the potential for work-over. It also shows a change In the GOC around well CIA at initial time and at the end of history match This confirmed the blowing down of the gas cap due to gas coning resulting in high GOR production. This reduced the effective contribution of the small gas cap allowing water influx to dominate and cause the GOC to move upward reducing well IOA producing GOR to solution GOR.

Production Optimization

Various scenarios were considered for optimizing production from the reservoir. However, four basic scenarios were simulated namely: 1) water production control, 2) work-over of existing conventional wells, 3) Re-drills of shut-in wells to horizontal completion and 4) partial gas-cap gas blow down. Table 2 shows the results of the different scenarios.

Water Production: Water production control aims at conserving the primary energy source, aquifer, and reducing the cost of water handling. Historical water production rate from each well is about 2500 stb/d while reservoir total has peaked at about 5000 stb/d. When the water production rare was constrained to 1500 stb/d per well and compared with 2500 stb/d per well case, reserves los, of more than 2 Mstb Was noted. This indicates that is no benefit to be achieved in controlling the water production because water production is not rate sensitive. Water breakthrough in this reservoir as earlier mentioned has been confirmed to be mainly a function cot aquifer encroachment rather than coning

Work-Over of existing conventional veils:

Due to the continued water influx and consequent flooding of the wells, re-completion of the wells to the highest structural position in the existing wellbore were considered and simulated When two of the wells, 01A 13A, were re-completed in the model and put back on production base case recovery improved by 12 %. However, the success of the actual re-completion of these wells is time dependent because the water contact continues to rise with production from well 10A. 1 he potential for re-completion will soon be flooded or become too small to justify.

Horizontal wells performance: Two horizontal wells were simulated as replacement for two of the shut in wells, Edop 01 A and ISA. The results also included in Table 2 show no significant recovery Improvement as a result of using horizontal wells over conventional wells Stratigraphic heterogeneity is known to contribute to the poor horizontal well performance and rapid water encroachment, especially in the high permeability layers. This result supports the earlier position that w1ter production from this reservoir is mainly a function of a strong and rapid aquifer encroachment rather than coning. The higher cost horizontal wells will perform similar to conventional wells in this reservoir,

Partial gas cap down: History match confirmed reduction in the gas cap volume due to excessive gas production and the possibility of gas oil contact moving into the gas cap zone. The simulation and material balance models confirmed dwindling of energy support from the gas cap. Well 10A already positioned at the structural peak of the reservoir was partly re- completed Into the initial gas cap. This re-completion was made towards (he abandonment phase of the reservoir and combined with the work-over scenario. This scenario did not consider total gas cap blow down, but it attempted to recover as much oil and gas as possible using Well 10A. Results, which are included In Table 2, show a significant improvement in reserve both in gas and oil over the work-over case. This result confirms additional benefits attributable to higher structural completion of wells in strong water drive reservoir. It also indicates the possibility that recovery may have been aided by natural gas lift using free gas from the gas cap.

CONCLUSIONS

The various analyses earned in this reservoir were aimed at understanding and optimizing the performance of the Edop BQI reservoir. The integrated approach of the geologist, reservoir and operations engineers yielded a better understanding of the reservoir.

Aquifer drive was determined as the single most important reservoir drive energy contributing about 85’X of the reservoir energy system. Characteristically this was with water breakthroughs with declining productivity. The strength of the aquifer was further confirmed by the small pressure decline with about 50% In-place recovery and the rate of aquifer encroachment as shown in the OWC movement.

Due to the strong aquifer and its rate of encroachment, constraining water production would not be beneficial in this type of reservoir. Since water production rate was not oil rate sensitive. The Use of horizontal completion to control water production may not yield any significant reserves improvement to justify its cost over conventional completions. Conventional well work-over and structural positioning of the wells could be used to maximize reserves. Production demands may require wells to flow with higher than normal water production rates, while gas lilt could he used to aid tubing vertical flow to Improve reserve recovery.

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